Shale Oil: An Acceptable Refinery Syncrude

H. C. Stauffer & S. J. Yanik

Gulf Science and Technology Company
P. O. Drawer 2038, Pittsburgh, PA 15230

Introduction

Technology for the extraction of oil from shale has been in existence for a very long time. In a less restrictive economic and environmental climate, the production of substantial quantities of shale oil could have been realized rather quickly. It has also been well established that shale oil must be substantially upgraded before any conventional refining processes can be applied.

No refinery has the capability of effectively processing any significant volume of raw shale oil. Therefore, most upgrading studies have two objectives: 1) produce a syncrude that can be pipelined and then refined in an existing facility, or 2) upgrade and refine to a full slate of products at the retort site. In either case, the overall upgrading requirements are substantial and quite similar.

Our upgrading studies were initiated in the 1960's. As a result of our participation in the Rio Blanco Project, these have been updated during the past few years. This paper presents the results of our most recent exploratory studies made to determine 1) the effectiveness of our commercially available hydrotreating technology for upgrading shale oil to a petroleum substitute and 2) the response obtained in conventional downstream refining processes.

Upgrading Routes

In upgrading shale oil for refining purposes, there are two general approaches. In the one most often considered, Figure 1, the raw oil is fractionated to yield a residuum that may be gasified, coked or deasphalted. A heavy gas oil is obtained for hydrocracking or hydrotreating for FCC feed. The furnace oil distillate is hydrotreated to No. 2 fuel (or additional FCC feed) and a naphtha is produced for hydrotreating and catalytic reforming. The syncrude from this route is, essentially, an all-distillate stream, comprised of the reconstituted, hydrotreated fractions.

A more unconventional approach, which avoids much duplication of facilities, is shown in Figure 2. In this route, the whole shale oil is hydrotreated in a modified Gulf Residual HDS Unit. The effluent can be pipelined as syncrude or fractionated and converted to prime products via reforming, hydrocracking and/or FCC. Volumetric yields are higher, by this route, and no residual products need be produced.

Discussion

Shale Oil Quality

Although all our latest pilot plant studies were limited to a single shale oil sample, a number of different oils were examined. Assays for five of these (A thru E) are shown in Table I. These data are indicative of the variation in shale oil composition that can result from differences in retorting modes and oil shale source. Obviously, as retorting technology changes, so can the character of the oil.

Regardless of oil shale source or retorting mode, all the oils are typified by their high hetero-atom content, with nitrogen being the highest, by far. Sulfur content is relatively low in all samples and of no particular concern. As would be expected, the hetero-atom content of the particular fractions varies from sample to sample as do the yields of these fractions. In view of the present trend toward in-situ retorting, the

lower residuum and hetero-atom content of sample E is encouraging. Sample A was used exclusively for all the pilot plant studies herein reported.

Experimental

In order to meet the objectives of this study, with the amount of shale oil available, most of the data was acquired from survey-type runs, using our early exploratory studies as a basis. All the pilot plant work was done in existing facilities normally used for petroleum-based feeds.

Delayed coking runs were made in a 2 gal/hr unit, equipped for downstream fractionation and gas oil recycle.

Catalytic cracking data was obtained in a 1,500 cc/hr, automated riser unit having product fractionation and continuous catalyst regeneration facilities.

Hydrogenation and catalytic reforming runs were also made in automated units, both isothermal and adiabatic. These units are equipped for downstream product fractionation and most have gas scrubbing and recycle systems. All operations were downflow, with combined hydrogen, in catalyst beds ranging from 300 to 2,500 cc.

Only commercially available catalysts were employed, with those for hydrogenation being Gulf formulations. The riser cracking runs were made with an equilibrium catalyst of high zeolite content. A commercially available bimetallic catalyst was used in the reforming studies.

Because of the inherently poor stability characteristics of raw shale oil, it was felt that the problems this could cause during the study could be alleviated by a mild hydrogen pretreatment. Thus, the entire sample was mildly hydrotreated, with the intent of eliminating the most reactive double bonds. Although hydrogen consumption was about 150 SCF/B, except for arsenic removal, the detectable changes in product properties and composition were insignificant. It was concluded that the pretreatment would have no effect on further processing. Thus, the studies were considered to be representative of upgrading a raw shale oil sample.

Delayed Coking of Residuum

Coking of the 960 F+ fraction was done at conditions previously found suitable for shale oil residua and no unexpected problems were encountered. The conventional, relatively mild conditions, with product yields and inspections, are shown in Table II. The liquid products are typical of a coker operation and, of course, very high in nitrogen. The coke is of relatively poor quality, very high in nitrogen content, but low in sulfur and vanadium. Ash content will be a function of the carry-over from the retorting operation. It was observed that the yield structure does not fit that predicted from a petroleum-based correlation. Coke yield was higher while gas and naphtha yields were lower.

Gas Oil Hydrotreating and Catalytic Cracking

The gas oil fraction, 680-960°F, was hydrotreated in two stages to produce feedstocks for catalytic cracking. Products of 0.73 and 0.61% nitrogen were obtained at two severities in the first stage. The higher nitrogen level material served as feed to the second stage. At two severities in this stage, nitrogen content was reduced to 0.28 and 0.10%; the lower level representing 95.9% overall denitrogenation. Yields, operating conditions and product inspections are shown in Table III. For comparison, the properties of a good quality, low nitrogen, petroleum gas oil (PGO) are also shown.

Except for the unique sulfur/nitrogen ratio, the hydrotreated shale oils (HTSO) exhibit no apparent unusual characteristics. As would be expected, however, boiling range does change with denitrogenation severity.

Since the products were not stripped back to feed IBP, they contain increasing amounts of material in the furnace oil boiling range. Based on properties other than nitrogen content, the quality of these synthetic gas oils is equal to or superior than that of many petroleum based FCC feedstocks.

The response obtained in fluid catalytic cracking is shown in Table IV. The yield structure produced from the HTSO's is compared with those from the PGO and two stocks which were blends of the PGO with the raw feed to hydrotreating. The HTSO's crack very well up to a nitrogen content of at least 0.28%. Of all the stocks, maximum conversion and gasoline yield was obtained with the low nitrogen HTSO. For the hydrotreated stocks, however, response is nonlinear with nitrogen content. At the 0.61% level, conversion and gasoline yield were much poorer than those obtained with the blended feed at the same nitrogen level. This discrepancy has been attributed to the high basic nitrogen content of the HTSO.

FCC Product Quality

With one exception, adequate octane numbers were obtained with all shale oil-containing feedstocks. All research octane numbers (RON) were 91 or greater except when cracking the low nitrogen HTSO, Table V. In this case, the RON was only 89.2. This gasoline had the highest saturate content and the lowest sensitivity. It was also derived from the most paraffinic feedstock.

Gasoline aromaticity was remarkably constant for all shale oil stocks, hydrotreated or blended, but lower than obtained with the PGO. As feed nitrogen increased, saturate content decreased with a corresponding gain in olefin content. Motor octane numbers obtained from the shale oil stocks were consistently lower than from the PGO. Sensitivity increased with feed nitrogen content. The increase, however, was not as great with the HTSO's as with the blended feeds.

Relative to the gasoline from the PGO, all shale oil stocks gave gasolines of much higher nitrogen content. Of these, the HTSO's gave the lowest values at comparable feed nitrogen levels. For the cycle oils and decanted oils, however, nitrogen contents were higher from the HTSO's than the blended feeds. All available data indicate satisfactory product stability up to a feed nitrogen level of at least 0.3%.

Middle Distillate Hydrotreating

Hydrogenation of the middle distillate fraction, 375-680°F, readily yields a high quality furnace oil product. As shown in Table VI, negligible sulfur content and high cetane index is easily obtained. Compared to petroleum derived furnace oils, however, nitrogen contents are quite high. This can be reduced to a very low level; but, it should not be required except for exclusive use in combustion applications were NO_x emissions are limiting. In all other respects, the combustion characteristics of these fuels are excellent(1) and in many cases superior to No. 2 fuels from petroleum.

Naphtha Pretreating and Reforming

Unlike heavier stocks in which substantial amounts of nitrogen can be tolerated, the naphtha must be essentially nitrogen-free for satisfactory reforming response. As the inspection data show, in Table VI, the nitrogen level is many orders of magnitude greater than typical for most virgin, petroleum-based naphthas. Nitrogen at this high level totally overwhelms the difficulty associated with removal of the remaining hetero-atoms. Figure 3 shows a temperature-space velocity-pressure relationship required to produce a reformer charge of 0.5 ppm nitrogen content. These conditions far exceed typical refinery pretreating severities.

The raw naphtha has a relatively high aromatic content and is very olefinic. About 85% of the hydrogen required is consumed in saturation reactions. The total consumption, 808 SCF/B, is in excess of that required for many gas oil hydrocrackers.

As reformer feed, the treated naphtha inspections show two important points. First, the front-end volatility is very low, indicating a deficiency in C_6 and C_7 hydrocarbons. Second, the ratio of naphthenes to aromatics is exceptionally high. Consequently, the reforming results show quite low benzene and toluene yields and a high hydrogen make.

The quality of the feed, as indicated by its N+2A relationship, is significantly better than would be predicted. Although this simple relationship would indicate reforming susceptibility close to that of a Mideast naphtha, such as Kuwait, its response was actually much closer to that of a good quality domestic naphtha. This is illustrated by the yields obtained and temperature requirements shown in Figures 4, 5 and 6.

Alternate Upgrading Route

The maximum yield case is shown in the alternate approach, Figure 2. In this route, the raw, full-boiling range shale oil is charged to a modification of the Gulf HDS Process. The results shown in Table VIII are for maximizing the yield of FCC feed at the minimum denitrogenation level. The yield of 375°F+ FCC charge is approximately 85% on raw crude and contains 0.38% nitrogen with <1.0 ppm Ni equivalent. Although the 375°F+ material is relatively high in nitrogen, the naphtha is essentially nitrogen-free and can be charged directly to a catalytic reformer.

This is not a limiting case; if the furnace oil fraction is desired for other end uses, the 680°F+ can still be reduced to a satisfactory nitrogen level. The residuum, which has an API gravity higher than that of the crude, may also be more useful in other applications.

Conclusions

For satisfactory hetero-atom removal, particularly nitrogen, and for olefin saturation, hydrogen requirements are substantial. With today's commercially available catalysts, processing severities are high and costly.

With respect to FCC feed, limited quantities of raw shale oil can be tolerated in a refinery crude slate. Handling the 650°F and lighter material would require a hydrotreating capability greater than usually available.

Shale oil fractions when suitably upgraded, are quite amenable to refining in conventional processes. Product yields and quality are comparable to those obtained with a good quality petroleum crude. Upgrading the total shale oil via the modified Gulf HDS Process results in an improved yield structure and a less complex facility.

New catalyst formulations are expected to substantially reduce process severity. This will strongly affect upgrading and refining economics.

Reference

(1) Dzuna, E. R., "Combustion Tests on Shale Oil Fuels", presented at Central States Section the Combustion Institute, April 1976.

TABLE I

ASSAYS OF RAW SHALE OILS

Sample	A	B	C	D	E
Source	Dow	Paraho	Superior	Occidental	--
Retort	Tosco	Paraho	Tosco	Tosco	In-Situ
Shale Oil					
Gravity, °API	20.7	20.1	20.7	19.3	25.4
Viscosity, SUS: 130°F	85.7	121.4	105.5	92.7	42.6
Pour, °F	+75	+85	+80	+50	+80
Carbon, wt %	84.52	84.83	84.06	83.97	84.89
Hydrogen, wt %	11.14	11.51	11.27	10.72	11.82
Sulfur, wt %	0.70	0.58	0.77	0.43	0.42
Nitrogen, wt %	1.99	2.04	2.06	1.96	1.62
Oxygen, wt %	1.32	1.24	1.58	1.92	1.09
Arsenic, ppm	13.9	20.9	8.0	32.0	19.0
Ash, wt %	0.20	0.03	0.05	0.06	0.26
Fractions:					
OP-310°F					
Yield, vol %	5.20	1.17	5.08	6.30	3.58
Gravity, °API	53.3	48.0	52.2	52.4	49.6
Carbon, wt %	85.06	84.20	84.11	84.87	85.84
Hydrogen, wt %	13.35	13.03	12.87	12.37	13.02
Sulfur, wt %	0.85	0.81	1.04	0.59	0.69
Nitrogen, wt %	0.25	0.95	0.41	0.30	0.59
Oxygen, wt %	0.52	0.75	0.95	0.69	0.49
Saturates, vol %	28.0	--	26.0	27.0	--
Olefins, vol %	56.0	--	54.0	57.0	--
Aromatics, vol %	16.0	--	20.0	18.0	--
Arsenic, ppm	--	5.2	1.5	3.4	1.6
310-375°F					
Yield, vol %	4.54	1.13	4.58	4.53	3.39
Gravity, °API	44.8	40.7	43.6	42.8	43.0
Carbon, wt %	84.84	83.44	84.36	84.72	84.14
Hydrogen, wt %	12.97	12.68	12.80	12.71	12.67
Sulfur, wt %	0.72	0.52	0.91	0.59	0.55
Nitrogen, wt %	0.65	1.46	0.82	0.79	1.09
Oxygen, wt %	0.70	1.46	1.24	0.87	0.77
Saturates, vol %	25.0	--	25.5	23.5	--
Olefins, vol %	52.0	--	48.0	48.0	--
Aromatics, vol %	23.0	--	26.5	28.5	--
Arsenic, ppm	--	1.8	<0.2	3.9	6.0
375-520°F					
Yield, vol %	12.64	9.60	10.87	13.64	20.49
Gravity, °API	35.0	33.8	34.3	33.0	34.1
Carbon, wt %	84.57	84.09	83.92	84.58	84.94
Hydrogen, wt %	12.32	12.38	12.30	12.02	12.31
Sulfur, wt %	0.64	0.68	0.74	0.39	0.36
Nitrogen, wt %	1.05	1.35	1.25	1.15	1.21
Oxygen, wt %	1.24	1.53	1.70	1.38	0.85
Pour, °F	-45	-30	-35	-55	-30
Aniline Point, °F	82.0	--	73.4	80.0	93.2
Arsenic, ppm	--	24.7	1.8	9.8	1.5

TABLE I (continued)

Sample	A	B	C	D	E
Fractions: (cont'd)					
375-680°F					
Yield, vol %	30.85	28.92	27.37	33.07	51.33
Gravity, °API	29.3	28.4	29.7	27.0	29.5
Viscosity, SUS: 100°F	40.1	42.6	40.2	42.1	39.3
Carbon, wt %	84.56	83.90	84.09	86.00	85.29
Hydrogen, wt %	11.96	11.98	12.01	11.83	12.03
Sulfur, wt %	0.63	0.69	0.70	0.44	0.37
Nitrogen, wt %	1.47	1.60	1.62	1.56	1.47
Oxygen, wt %	1.26	1.27	1.72	1.60	0.75
Pour, °F	+15	+20	+30	+5	+20
Aniline Point, °F	87.1	--	86.0	82.4	102.2
Arsenic, ppm	8.0	23.0	3.8	20.4	5.7
680-960°F					
Yield, vol %	32.57	37.81	31.93	31.73	33.79
Gravity, °API	16.3	18.6	18.6	15.3	20.8
Viscosity, SUS: 210°F	66.4	57.0	56.0	91.0	50.7
Carbon, wt %	85.01	85.11	86.11	85.16	87.02
Hydrogen, wt %	10.93	11.25	11.53	10.96	11.84
Sulfur, wt %	0.60	0.53	0.65	0.36	0.24
Nitrogen, wt %	2.09	1.91	2.08	2.00	1.75
Oxygen, wt %	0.94	0.83	1.18	1.20	0.68
Pour, °F	+100	+100	+100	+85	+105
Aniline Point, °F	126.0	--	111.9	118.4	135.5
Carbon Res, wt %	0.91	0.28	0.41	0.44	0.40
Arsenic, ppm	--	12.8	15.5	29	14
Ni + V, ppm	<0.1	<0.1	0.1	<0.1	<0.1
960°F+					
Yield, vol %	26.84	30.97	31.04	24.37	7.91
Gravity, °API	5.9	11.8	9.2	5.3	6.8
Viscosity, SUS: 250°F	1,159	266	503	3,212	2,216
Carbon, wt %	85.14	84.61	84.81	85.20	84.85
Hydrogen, wt %	10.61	10.64	10.37	9.74	10.24
Sulfur, wt %	0.64	0.53	0.80	0.39	0.58
Nitrogen, wt %	2.84	2.60	2.78	2.95	2.26
Oxygen, wt %	1.34	0.95	1.31	1.20	2.05
Carbon Res, wt %	20.3	12.9	15.8	24.4	18.4
C_5 Insolubles, wt %	18.1	--	15.4	20.7	18.0
Ash, wt %	0.64	0.05	0.13	0.21	2.28
Arsenic, ppm	--	26.0	7.0	59.0	67.0
Ni, ppm	15	9.2	20.8	32.0	45.6
V, ppm	1.6	0.5	1.8	0.5	22.8

TABLE II

RESIDUUM DELAYED COKING

Operating Conditions					
Temperature, °F:					
Furnace Outlet			850		
Coke Drum			850		
Coke Drum Press.,psia			60		
Yields, % of Feed					
H_2S, wt %			0.02		
H_2, wt %			0.03		
C_1, wt %			1.7		
C_2, wt %			1.4		
C_3, wt %			1.2		
Naphtha, (C_4-400°F), vol %			18.0		
Furnace Oil (400°-650°F), vol %			23.9		
Gas Oil (650°-950°F), vol %			29.2		
Coke, wt %			35.2		
Inspections	**Feed**	**Naphtha**	**Fur. Oil**	**Gas Oil**	**Coke**
Gravity, °API (Sp.Gr.)	6.1	53.6	32.0	17.4	(1.3)
Nitrogen, wt %	2.86	0.57	1.06	2.0	5.8
Sulfur, wt %	0.63	0.31	0.45	0.90	0.75
Hydrogen, wt %	9.83	-	-	-	-
Bromine No.	-	46	-	-	-
Viscosity, SUS:					
100°F	-	-	36.0	-	-
210°F	4,463	-	-	63.2	-
Aniline Pt, °F	-	-	114.1	150.0	-
Carbon Res.,Con.: wt %	20.6	-	-	-	-

TABLE III

GAS OIL HYDROTREATING

Hydrotreatment		First Stage	Second Stage		
		680°/960°F			
Feed		Gas Oil	First Stage Product		
Operating Conditions:					
Reactor Press., psig		<----------1,725---------->			
Gas Circulation, SCFB		4,000	<---- 8,500 ---->		
Avg. Catalyst Temp., °F		725	720	755	
Space Velocity, vol/hr/vol		1.0	1.0	0.75	
Yields, Wt % of Feed:					
H_2 (SCFB)		(1,200)	(450)	(630)	
H_2S		0.49	0.04	0.04	
NH_3		2.19	0.55	0.77	
H_2O		0.90	-	-	
C_1-C_5		4.08	0.42	1.56	
Total Liquid Product		94.21	99.75	98.70	
Inspections:	Gas Oil				PGO
Nitrogen, wt %	2.41	0.61	0.28	0.10	0.063
Gravity, °API	13.9	27.4	29.7	31.2	26.9
Hydrogen, wt %	10.85	12.56	13.00	13.18	12.77
Sulfur, wt %	0.49	<0.05	<0.05	<0.05	0.47
Oxygen, ppm	0.80	<100	<100	<100	-
Viscosity, SUS:					
210°F	118.4	41.4	37.7	35.8	41.7
Pour Point, °F	+105	+95	+80	+85	+90
Aniline Point, °F	101	174.6	181.9	186.1	190.0
Carbon Res., Rams.: wt %	1.34	0.12	0.07	0.05	0.26
Calc. Comp.,					
Vol Fraction:					
Aromatics(Ca)	-	0.205	0.170	0.147	0.160
Naphthenes(Cn)	-	0.212	0.218	0.220	0.231
Paraffins(Cp)	-	0.583	0.612	0.633	0.610
Nickel, ppm	<0.1	<0.1	<0.1	<0.1	0.2
Vanadium, ppm	<0.1	<0.1	<0.1	<0.1	0.9
Distillation, Vac.,					
°F at:					
10%	805	611	517	484	622
30	869	730	688	661	695
50	905	784	779	763	770
70	939	839	843	827	851
90	989	917	893	870	953

TABLE IV

CATALYTIC CRACKING AT 980°F RISER OUTLET TEMPERATURE-PRODUCT YIELDS

Feed	PGO	<----------Hydrotreated---------->			<-----PGO + RAW SOGO*------>	
Nitrogen, wt %	0.063	0.10	0.28	0.61	0.29	0.61
Product Yields:						
Vol % FF						
Total C_3's	13.0	12.1	11.8	8.1	11.7	10.5
Propane	2.5	2.2	2.1	1.7	2.3	2.6
Propylene	10.5	10.0	9.7	6.4	9.4	7.9
Total C_4's	20.8	20.7	19.1	10.8	18.2	13.3
Isobutane	8.3	7.8	6.2	2.1	6.0	3.4
Normal Butane	2.0	2.0	1.6	0.9	1.6	1.1
Butenes	10.5	10.9	11.2	7.8	10.6	8.8
Debutanized Gasoline:						
C_5-430°F TBP	60.6	62.4	60.5	41.7	58.5	50.7
Furnace Oil:						
430°-650°F TBP	11.4	11.8	13.2	19.2	13.5	16.9
Decant Oil:						
650°F+	6.1	5.0	6.2	20.9	8.3	12.7
Total C_3+ Liquid	111.9	112.1	110.7	100.8	110.2	104.0
Product Yields:						
Wt % FF						
Hydrogen	0.09	0.05	0.09	0.15	0.11	0.13
C_2 and Lighter	3.0	2.4	2.7	4.4	3.0	3.7
Coke	6.1	4.6	5.1	6.4	5.8	7.9
Conversion: Vol % FF	82.5	83.2	80.7	59.9	78.2	70.4

*680°/960°F shale oil/gas oil

TABLE V

CATALYTIC CRACKING AT 980°F RISER OUTLET TEMPERATURE-PRODUCT QUALITY

Feed	PGO	<--------Hydrotreated-------->			<--PGO + RAW SOGO-->	
Nitrogen, wt %	0.063	0.10	0.28	0.61	0.29	0.61
Inspections						
C_5-430°F Gasoline						
Gravity, °API	55.6	57.2	56.3	51.1	56.0	53.9
Nitrogen, ppm	14	60	130	980	163	630
Research Octane Numbers						
Clear	92.6	89.2	91.1	91.0	93.7	93.2
+3.0	99.6	99.5	98.5	97.4	99.5	97.9
Motor Octane Numbers						
Clear	81.6	79.3	80.2	78.5	79.8	80.3
+3.0	88.1	87.6	86.7	84.7	85.3	87.3
Hydrocarbon Type, vol %						
Aromatics	33.0	25.7	25.7	25.9	26.8	25.6
Olefins	20.3	23.7	33.6	51.4	36.1	44.9
Saturates	46.7	50.6	40.6	22.7	37.2	29.5
430°-650°F Furnace Oil						
Gravity, °API	14.0	17.2	18.5	24.6	19.6	23.0
Nitrogen, wt %	0.03	0.11	0.17	0.43	0.09	0.26
Pour Point, °F	-20	-40	-25	+25	-10	+10
Hydrocarbon Type, vol %						
Aromatics	83.9	73.2	66.6	45.7	64.6	49.7
Olefins	0.1	0.1	1.3	11.3	2.5	0.0
Saturates	16.0	26.7	32.1	43.0	32.9	50.3
650°F+ Decant Oil						
Gravity, °API	1.7	2.6	6.0	20.0	6.3	11.9
Nitrogen, wt %	0.12	0.20	0.33	0.37	0.21	0.37
Viscosity, SUS:						
210°F	46.0	70.6	58.0	-	44.9	44.4

TABLE VI

FURNACE OIL HYDROTREATING

Operating Conditions					
Reactor Press., psig		<----------1,750---------->			
Gas Circulation, SCFB		<----------5,000---------->			
Avg. Catalyst Temp., °F		<----------710---------->			725
Space Velcoity, vol/hr/vol		0.51	0.99	1.52	1.0
Yield, Vol %					
Naphtha-Free Furnace Oil		99.8	99.0	100.8	99.1
Inspections	Feed				
Gravity, °API	29.3	39.7	38.9	37.4	39.1
Nitrogen, wt %	1.66	0.038	0.27	0.57	0.17
Sulfur, wt %	0.77	<0.04	<0.04	<0.04	<0.04
Hydrogen, wt %	12.09	13.80	13.54	13.45	13.66
Oxygen, ppm	1.20	<100	580	1,620	320
Flash, PM: °F	185	182	162	144	170
Pour Point, °F	+20	+10	+10	+20	+10
Cetane Index	41	58.0	56.0	53.5	55.5
Aromatics, vol %	-	26.0	36.5	43.5	28.0
Distillation, D86					
°F at:					
10%	453	430	423	426	424
30	493	468	469	475	464
50	534	509	505	511	500
70	574	550	550	554	540
90	612	599	601	606	595

TABLE VII

NAPHTHA PRETREATING AND REFORMING

Operating Conditions		Pretreating	Reforming	
Reactor Press., psig		1,400	<------325-------->	
Gas Circulation, SCFB		8,000	-	
Space Velocity, vol/hr/vol		1.0	<------1.5-------->	
H_2/HC, mol/mol		-	<------7/1-------->	
Avg. Catalyst Temp., °F		680	366	880
Yields, wt % of Feed				
H_2(SCFB)		(-808)	2.0	2.2
H_2S		0.84	-	-
NH_3		0.69	-	-
H_2O		0.61	-	-
C_1		0.20	1.2	1.4
C_2		0.02	2.0	2.4
C_3		0.08	3.8	4.6
C_4		0.14	5.3	6.2
C_5+ Product (vol %)		103.0	81.9	78.8
Inspections	Feed			
Gravity, °API	47.8	54.7	46.4	44.7
Nitrogen, ppm	5,700	<0.2	-	-
Sulfur, ppm	7,900	<0.5	-	-
Oxygen, ppm	5,400	<100	-	-
Hydrogen, wt %	13.28	14.77	-	-
Bromine Number	66	-	-	-
Hydrocarbon Analysis,				
D1319, vol %				
Saturates	38.0	-	-	-
Olefins	43.5	-	-	-
Aromatics	18.5	-	-	-
D2789, vol %				
Paraffins	-	58.8	44.0	38.7
Monocycloparaffins	-	30.6	3.2	2.7
Dicycloparaffins	-	3.9	0.1	0.1
Alkylbenzenes	-	6.1	50.7	56.7
Benzene	-	0.1	0.9	1.3
Toluene	-	0.6	6.4	7.9
C_8	-	1.7	13.0	15.5
C_9+	-	3.7	27.8	32.0
Indanes & Tetralins	-	0.4	1.6	1.3
Naphthalenes	-	0.2	0.5	0.5
Octane Numbers:				
Research, Clear	-	29.0	92.9	96.7
Motor, Clear	-	-	82.9	86.0
Distillation, °F at:				
10%	279	262	181	178
30	300	284	-	-
50	316	304	286	282
70	334	325	-	-
90	354	349	358	358

TABLE VIII

UPGRADING FBR RAW SHALE OIL

Operating Conditions			
Reactor Press., psig		2,100	
Gas Circulation, SCFB		5,000	
Avg. Catalyst Temp, °F		750	
Space Velocity, vol/hr/vol		0.5	
Yields, % of HDS Charge			
H_2S, wt %		0.72	
NH_3, wt %		2.05	
H_2O, wt %		1.45	
C_1-C_4, wt %		2.09	
C_5+ Syncrude, vol %		102.6	
Chem. H_2 Consumption, SCFB		1,260	
Inspections	Feed		Syncrude
Syncrude:			
Gravity °API	20.7		31.5
Nitrogen, wt %	1.99		0.32
Sulfur, wt %	0.70		<0.05
Oxygen, wt %	1.32		0.03
Hydrogen, wt %	11.14		12.84
Pour Point, °F	+75		+70
Fractions:			
Naphtha (C_5-375°F)			
Yield: vol % Syncrude		16.7	
Gravity, °API		53.7	
Nitrogen, ppm		<0.5	
Sulfur, ppm		<0.5	
Furnace Oil (375°-680°F)			
Yield: vol % Syncrude		43.7	
Gravity, °API		36.0	
Nitrogen, wt %		0.23	
Sulfur, wt %		<0.05	
Aniline Point, °F		149	
Pour Point, °F		+10	
Gas Oil (680°-960°F)			
Yield: vol % Syncrude		24.3	
Gravity, °API		27.2	
Nitrogen, wt %		0.43	
Sulfur, wt %		<0.05	
Aniline Pt, °F		189	
Pour Point, °F		+95	
Residuum (960°F+)			
Yield: vol % Syncrude		15.3	
Gravity, °API		22.4	
Nitrogen, wt %		0.68	
Sulfur, wt %		<0.05	
Ni Equiv.,ppm		<1.0	

Figure 1.

CONVENTIONAL UPGRADING ROUTE

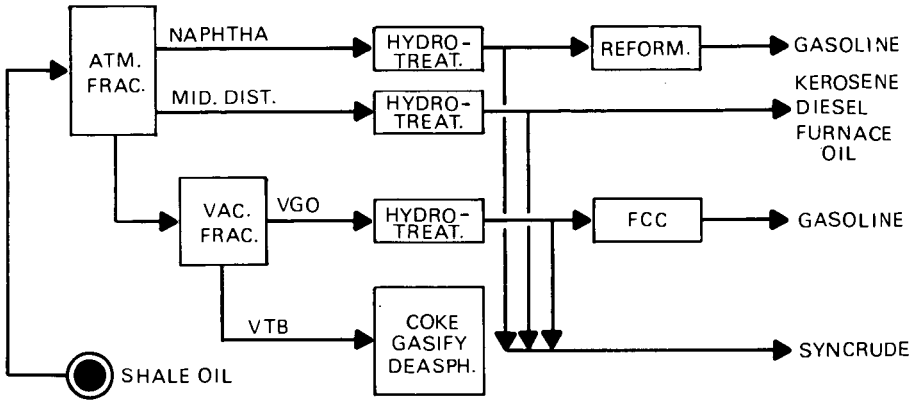

Figure 2.

ALTERNATE UPGRADING ROUTE

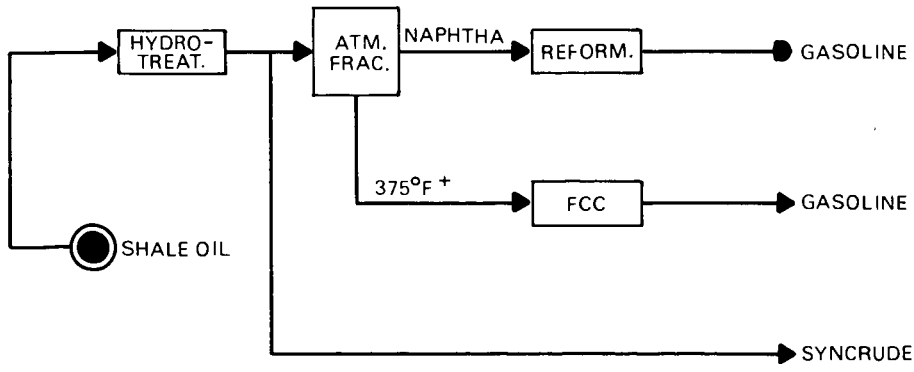

Figure 3

NAPHTHA HYDROTREATING

TEMPERATURE REQUIREMENTS FOR 0.5 ppm N

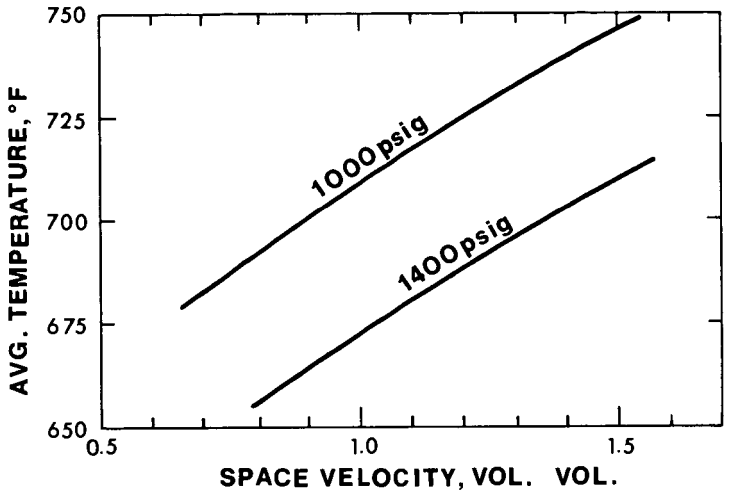

Figure 4

NAPHTHA REFORMING

C_5^+ YIELD VS OCTANE SEVERITY

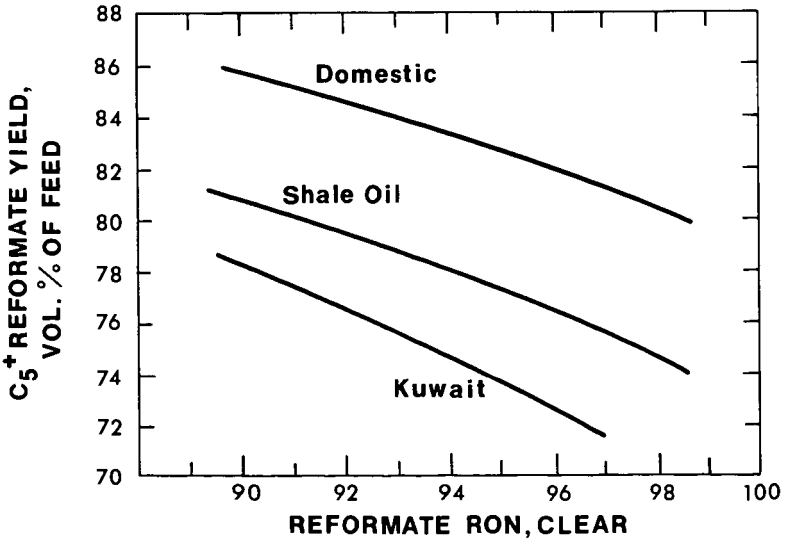

Figure 5
NAPHTHA REFORMING
H_2 PRODUCTION VS OCTANE SEVERITY

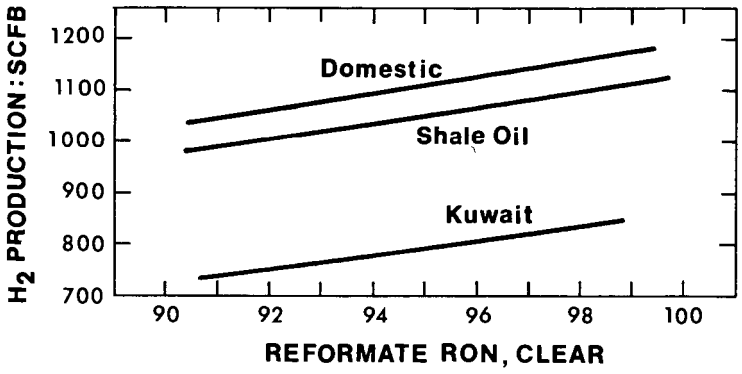

Figure 6
NAPHTHA REFORMING
AVG. CATALYST TEMP. VS OCTANE SEVERITY